

Before the Public Service Commission
of the State of Wyoming

Joint Application of
Cheyenne Light, Fuel and Power Company and Black Hills Power, Inc.
For a Certificate of Public Convenience
and Necessity for a Gas-Fired
Electric Generating Power Plant and
Related Facilities

Docket No. 20003-113-EA-11

Record No. 13007

Docket No. 20002-81-EA-11

June 18, 2012



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EXHIBITS

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Confidential Exhibit Colorado IPP Facility Analysis

I. INTRODUCTION AND BACKGROUND

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. Kyle D. White, 625 Ninth Street, P. O. Box 1400, Rapid City, South Dakota.

3 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

4 A. I am Vice President of Resource Planning and Regulatory Affairs for Black Hills
5 Corporation. My areas of responsibility include resource planning for the regulated
6 electric utility subsidiaries of Black Hills Corporation.

7 **Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF OF TODAY?**

8 A. I am testifying on behalf of Cheyenne Light, Fuel and Power Company ("Cheyenne
9 Light") and Black Hills Power, Inc. ("Black Hills Power").

10 **Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?**

11 A. Yes, I did.

II. PURPOSE OF TESTIMONY

13 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

14 A. I will describe the rationale for why Cheyenne Light and Black Hills Power conducted
15 separate integrated resource planning (IRP) analyses. I describe the range of options
16 examined in conducting the IRP. I will describe the business decision to proceed with a
17 jointly-owned combined cycle unit in Cheyenne, Wyoming, which was made after
18 significant analysis demonstrated that this was the most prudent decision to meet the
19 long-term needs of the customers of both Cheyenne Light and Black Hills Power in the
20 least cost, least risk manner. I will discuss the business case for utility-owned resources
21 versus power purchase agreements. I will discuss the manner in which the operations of
22 Cheyenne Light and Black Hills Power are currently integrated.

1 **III. NEED**

2 **Q. DOES THE OFFICE OF CONSUMER ADVOCATE'S (OCA) TESTIMONY**
3 **DISPUTE THE NEED FOR ADDITIONAL CAPACITY TO MEET THE**
4 **ELECTRICITY REQUIREMENTS OF CHEYENNE LIGHT AND BLACK**
5 **HILLS POWER?**

6 A. No.

7 **IV. SEPARATION OF THE IRPS OF CHEYENNE LIGHT AND BLACK HILLS**
8 **POWER**

9 **Q. PLEASE PROVIDE A HISTORY OF THE INTEGRATED RESOURCE PLANS**
10 **PREPARED BY CHEYENNE LIGHT AND BLACK HILLS POWER.**

11 A. Cheyenne Light was acquired by Black Hills Corporation on January 21, 2005. In March
12 of 2005, an IRP was filed with the Commission that presented analysis for Cheyenne
13 Light and Black Hills Power both on a stand-alone basis and as a combined system. A
14 coal-fired unit was recommended as the preferred resource in the 2005 IRP resource
15 portfolio. The 90 MW coal-fired Wygen II was built in Gillette, Wyoming, which is a
16 Cheyenne Light 100%-owned resource. In 2007, an IRP was conducted for the
17 Cheyenne Light and Black Hills Power systems combined. A coal-fired unit was
18 recommended as the preferred resource in the 2007 IRP resource portfolio. The 100 MW
19 coal-fired Wygen III was built in Gillette, Wyoming, which is a Black Hills Power owned
20 resource.

21 **Q. WHY WERE THE SYSTEMS COMBINED IN THE 2005 AND 2008 IRPS?**

22 A. The systems were combined because at that time in Black Hills Corporation's history, we
23 were considering the possibility of evolving the operations of both companies into a

1 generation pool and believed that it was appropriate to plan for resources on a combined
2 basis.

3 **Q. HAS THAT GENERATION POOL COME ABOUT?**

4 A. No, it has not. Developing a fully-integrated generation pool is a very complex legal and
5 regulatory process. I determined, and continue to believe, that the benefits for our utility
6 customers of separately planned and developed power supplies outweigh the costs and
7 complications of developing a fully-integrated generation pool. In addition, many of the
8 customer benefits associated with a fully-integrated generation pool have been
9 accomplished through the integration of other services and the joint dispatch of the
10 utility's systems under the Generation Dispatch and Energy Management agreement
11 between Black Hills Power and Cheyenne Light.

12 **Q. WERE CHEYENNE LIGHT AND BLACK HILLS POWER PREVIOUSLY**
13 **CRITICIZED FOR CONDUCTING IRPS ON A COMBINED SYSTEM BASIS?**

14 A. Yes, we were. Our understanding from the regulatory processes associated particularly
15 with the Wygen III unit was that future IRPs should be conducted for Cheyenne Light
16 and Black Hills Power each on a stand-alone basis. In particular, the Wyoming OCA
17 filed testimony in the CPCN docket for Wygen III that was critical of the company's
18 decision to conduct a joint IRP. In addition, staff of the South Dakota Public Utilities
19 Commission specifically requested that future IRP's be conducted on a stand-alone basis
20 as part of the settlement of Black Hills Power's South Dakota rate case that included
21 Wygen III capital and operating costs in base rates.

22 **Q. IS IT APPROPRIATE FOR IRPS TO BE CONDUCTED SEPARATELY FOR**
23 **CHEYENNE LIGHT AND BLACK HILLS POWER?**

1 A. Yes, it is. Cheyenne Light and Black Hills Power are separate legal entities and have
2 separate certificates of public convenience and necessity to serve customers. Customer
3 loads of the companies are forecasted separately, and the companies have their own
4 supply-side resources. At present, there is no company-owned transmission that connects
5 the two utilities directly, although there is transmission owned by others for which
6 Cheyenne Light and Black Hills Power have contracted.

7 **Q. WHEN THE RESOURCE PLANNING PROCESS BEGAN, COULD THE**
8 **COMPANIES HAVE CONDUCTED A JOINT IRP?**

9 Yes. The companies could have conducted a joint IRP, as was done in 2005 and 2008.
10 When the resource planning process began, however, the company did not know that the
11 opportunity to add a jointly-owned resource for the benefit of customers of both utilities
12 would present itself. The future resources that are going to be selected when an IRP is
13 conducted are not known or selected in advance of the planning process. In this case, as
14 you can see from our testimony, our application, and this rebuttal testimony, the results of
15 the Black Hills Power IRP changed senior management's thinking as to the best resource
16 for both Cheyenne Light and Black Hills Power after the IRPs were completed for each
17 on a stand-alone basis.

18 **V. RESOURCE OPTIONS CONSIDERED IN THE IRPS**

19 **Q. DO YOU AGREE WITH MR. FREEMAN (PAGE 14, LINES 2 AND 3) THAT**
20 **CHEYENNE LIGHT AND BLACK HILLS POWER LIMITED THE SCOPE OF**
21 **THE OPTIONS STUDIED IN THE IRP?**

22 A. No, I do not. The IRP effort focuses on identification of the resource need as well as the
23 type and timing of the resources most appropriate to meet the identified power supply

1 requirements. A complete range of demand-side and supply-side options was considered
2 in each utility's IRP. The demand-side options are enumerated in each company's IRP
3 and include such programs as lighting, water heating, refrigerator recycling, heat pumps,
4 school-based energy efficiency, energy audits and weatherization teams for residential
5 customers and prescriptive rebates and custom rebates for commercial customers.
6 Supply-side options included coal, different configurations of natural gas-fired combined
7 cycle (CC), and several types of natural gas-fired simple cycle combustion turbines
8 (CTG), unit upgrades, conversion from combustion turbine to combined cycle, firm
9 market purchases, wind, and solar.

10 The selection of the best or optimal resources is generally determined after the
11 IRP modeling has been completed. This is the approach that was used to select the
12 Cheyenne Prairie Generation Station (CPGS) as the least cost, least risk option.

13 **Q. PLEASE ADDRESS MR. FREEMAN'S ASSERTION ON PAGE 14, LINES 7**
14 **THROUGH 12, THAT THE COMPANY DID NOT ADDRESS CONTRACTUAL**
15 **ARRANGEMENTS WITH THIRD PARTIES FOR CAPACITY.**

16 A. I believe that company personnel, through their daily dealings with counterparties,
17 through their participation in the Rocky Mountain Reserve Group, and through their
18 membership in the Western Electricity Coordinating Council (WECC), Rocky Mountain
19 Electrical League (RMEL), and other utility associations, have a thorough understanding
20 of the resources available both contractually and for outright purchase in the Western
21 region. In each company's IRP, we modeled firm purchases from the market as a supply-
22 side option. These firm market purchases would in fact be contractual arrangements with
23 third parties for capacity.

1 **Q. OCA WITNESS FREEMAN HAS CRITIZED CHEYENNE LIGHT FOR**
2 **LIMITING ITS FIRM MARKET PURCHASES TO 50 MW. WHY WAS 50 MW**
3 **SELECTED AS THE CAP FOR FIRM MARKET CAPACITY AND NOT SOME**
4 **HIGHER NUMBER?**

5 A. In Cheyenne Light's judgment, 50 MW is the maximum amount that should be purchased
6 from the market. 50 MW represents 25% of Cheyenne Light's load. Increasing the level
7 of firm market purchases increases the risk that the utility will be forced to purchase
8 power in a market with prices higher than could be supplied through utility-owned
9 generation. Early in the last decade, before Cheyenne Light was owned by Black Hills
10 Corporation, Cheyenne Light was forced to buy power in a market with highly inflated
11 prices when a Cheyenne Light power purchase agreement was terminated at the height of
12 the electricity crisis in the western United States. The rate shock for customers was
13 severe. A balanced portfolio, including demand-side management, baseload resources,
14 intermediate resources, peaking resources, and purchased resources, allows the utility to
15 take advantage of market energy when market prices are low but reduces risk for its
16 customers when market prices are high or when market purchases are curtailed or
17 unavailable.

18 **Q. MR. FREEMAN ASSERTS ON PAGE 14, LINES 7 THROUGH 12, THAT**
19 **CHEYENNE LIGHT AND BLACK HILLS POWER DID NOT ADDRESS THE**
20 **POSSIBLE ACQUISITION OF GENERATION FROM A THIRD PARTY.**
21 **PLEASE DISCUSS THE ACTIONS OF UTILITY MANAGEMENT REGARDING**
22 **THE POSSIBILITY OF PURCHASING EXISTING GENERATION.**

1 A. Utility management first identified, through the modeling for the IRPs, the type of
2 resource that best fit the expected customer requirements. The resources identified were
3 natural gas-fired intermediate and peaking resources, with Cheyenne Light favoring
4 peaking resources and Black Hills Power favoring intermediate resources. The Black
5 Hills Power preference was due to its plans to retire baseload coal-fired generation to
6 ensure compliance with the new Environmental Protection Agency's (EPA) Boiler
7 Maximum Achievable Control Technology (MACT) rules which take effect in 2014.
8 The Companies then completed an assessment of the regional electricity market.

9 **Q. PLEASE DESCRIBE HOW THE COMPANIES ASSESSED THE REGIONAL**
10 **ELECTRICITY MARKET.**

11 A. The Companies are active participants in the regional electricity market and have a strong
12 familiarity with the generation serving loads in the area and the changes that have been
13 proposed. Our assessment was limited to the Wyoming and Colorado markets due to a
14 desire to limit transmission expenses for the needed resources.

15 Wyoming has limited installed natural gas-fired generation and they are all
16 situated to the north of Cheyenne. The transmission paths to Cheyenne Light,
17 particularly the paths where energy is flowing from north to south, are currently
18 constrained. The Cheyenne Light system receives energy from Wygen I and Wygen II
19 across the Loveland Area Project (LAPT) transmission paths through Dave Johnson and
20 Stegall substations. Currently, Cheyenne Light has transmission rights on the north to
21 south path of LAPT for 167 MW, only 15 MW more than their capacity ownership in
22 Wygen I and Wygen II. Cheyenne Light would need to procure additional transmission
23 on the north to south path of the existing LAPT system or build transmission

1 infrastructure, at a significant cost per mile, in order to deliver the energy to Cheyenne
2 Light's customers that is generated by a plant located north of Cheyenne.

3 Colorado has a more active independent power environment (IPP) and, as a prior
4 and current IPP participant and utility operating in Colorado, Black Hills Corporation is
5 well aware of the situation and the possibilities for acquiring IPP generation and
6 converting it to utility rate-based generation. Attached is confidential Exhibit 41 that
7 provides the information that was considered by utility management to determine that
8 constructing new generation was preferable to pursuing the acquisition of existing IPP
9 generation in Colorado. This analysis indicated that the seven existing independent
10 power producer (IPP) facilities located in Colorado that have expiring PPAs in the next
11 seven years are not suitable for Cheyenne Light's and Black Hills Power's customer's
12 needs due to size, type of generation, transmission costs and runtime restrictions. Many
13 of these facilities have tolling agreements and the gas supply is provided by Xcel Energy.
14 This allows Xcel to optimize gas supply arrangements between its electric and gas
15 departments but eliminates the opportunity for Cheyenne Light to optimize their gas
16 supply and transportation arrangements with its own gas distribution division. All of the
17 IPP facilities are interconnected with the Xcel Energy transmission system requiring the
18 owners to pay wheeling costs on the Xcel Energy system, and possibly other systems, to
19 deliver the capacity and energy to Cheyenne Light's customers. In addition, all of these
20 IPP facilities except the Tri-State facilities have run time restrictions due to emissions or
21 fuel limits in their air permits.

22 **Q. WHAT DID YOU CONCLUDE FROM YOUR ASSESSMENT OF THE**
23 **EXISTING GENERATION IN WYOMING AND COLORADO?**

1 A. We determined that the existing natural gas-fired generation within Wyoming and
2 Colorado that had expiring PPAs over the next seven years are not suitable for the needs
3 of the customers of Cheyenne Light and Black Hills Power and would not provide the
4 full range of benefits that will be provided through the proposed generation located in
5 Cheyenne.

6 **Q. DID YOU ALSO CONSIDER WHETHER A PPA MIGHT BE AVAILABLE**
7 **THAT WOULD WORK FOR MEETING THE UTILITIES' DEMONSTRATED**
8 **NEED FOR ADDITIONAL POWER SUPPLY?**

9 A. We expect that some capacity and related energy will be available for purchase in
10 Colorado over the new few years and, in fact, this assumption that some market power
11 would be available was modeled in each utility's IRP. As far as entering into a long-term
12 PPA, we do not believe that this approach results in long-term favorable outcomes for
13 customers. I discussed this on page 12 of my direct testimony where I said "in nearly
14 three decades that I have worked in the utility industry, I have seen the results of both
15 long-term power purchase relationships and utility-owned generation. I have come to
16 strongly believe that the best resource acquisition for meeting the majority of customer
17 electricity requirements is to own and control generation." I further discussed the
18 advantages of utility-owned generation.

19 **Q. COULD CHEYENNE LIGHT OR BLACK HILLS POWER PARTICIPATE IN**
20 **THE DEVELOPMENT OF NEW LARGER GENERATION OF OTHER**
21 **PARTIES?**

22 A. Yes.

1 **Q. ARE YOU AWARE OF ANY OPPORTUNITIES TO PARTICIPATE IN LARGER**
2 **PROJECTS IN COLORADO, SOUTH DAKOTA, OR WYOMING?**

3 A. No, I am not aware of any proposed projects in which we could participate. Even if there
4 were, participating with others in peaking or intermediate generation creates operating
5 challenges when only some of the parties need or desire to run the generation. This is
6 because generation has minimum loading requirements. The lower the loading, the less
7 efficient the operation of the unit (heat rate or fuel consumption per MWh produced).
8 This concern has been addressed between Cheyenne Light and Black Hills Power through
9 the rights to operate each other's share and the fact that the peak load time periods of the
10 utilities are similar, allowing for a high probability that both would call upon the
11 generation at the same time, which allows for an improved heat rate.

12 **Q. DID BLACK HILLS POWER ASSESS THE COST EFFECTIVENESS OF THE**
13 **CONVERSION OF EXISTING COAL-FIRED UNITS TO NATURAL GAS?**

14 A. Yes, Black Hills Power did consider the conversion of three of its coal-fired plants to
15 natural gas. The three coal-fired plants that are owned by Black Hills Power and are
16 subject to the new Environmental Protection Agency's (EPA) Boiler Maximum
17 Achievable Control Technology (MACT) rules which take effect in 2014 are the Osage,
18 Ben French, and Neil Simpson I units.

19 The effective conversion of coal-fired generation to natural gas depends on many
20 factors such as the age and size of the unit and the available natural gas supply. The
21 generation that Mr. Freeman cites in his rebuttal testimony, Naughton Unit 3, is a 330
22 MW coal-fired unit that was placed in service in 1971. The units owned by Black Hills
23 Power are individually smaller than 35 MW and were each put into service prior to 1970.

1 The Black Hills Power units do not have the economies of scale associated with
2 Naughton 3 over which to allocate the costs of conversion in addition to the upgrades
3 required for the unit to meet current emissions standards.

4 In addition, the current natural gas supplies at the Ben French and the Osage
5 facilities are insufficient to support natural gas-fired generation. Thus, the installation of
6 many miles of natural gas pipeline would be required (approximately 50 miles for the
7 Ben French facility and 20 miles for the Osage facility at a cost estimated at \$1 to 1.5
8 million per mile). Although the Neil Simpson I plant does have an adequate gas supply,
9 the risk associated with acquiring an air permit for the conversion of this plant is
10 significant. Neil Simpson I is located at Black Hills Corporation's Gillette Energy
11 Complex and acquiring an air permit for the conversion of Neil Simpson I would require
12 a revision to the air permit for the entire complex, putting all the generation facilities at
13 that location at risk.

14 **Q. WERE OTHER FACTORS CONSIDERED IN THE EVALUATION OF THE**
15 **CONVERSION OF EXISTING COAL-FIRED UNITS TO NATURAL GAS?**

16 **A.** Yes. Black Hills Power considered the impact on each unit's heat rate of a coal to natural
17 gas conversion. Black Hills Energy Colorado Electric, an affiliate of Black Hills Power,
18 owns and operates a plant that was converted from coal to natural gas and that now
19 operates at a 15,000 Btu/kWh heat rate. This was compared to the heat rate of a new
20 combustion turbine generator (CTG) in the range of 9,600 Btu/kWh.

21 **Q. WHAT IS YOUR CONCLUSION ABOUT THE ECONOMIC FEASIBILITY OF**
22 **CONVERTING THE BLACK HILLS POWER SMALLER COAL-FIRED UNITS**
23 **TO NATURAL GAS?**

1 A. After consideration of the natural gas supply situation, risks associated with permitting,
2 and the resulting expected efficiency of the units, it is not economically feasible for the
3 Ben French, Osage, or Neil Simpson I units to be converted from coal to natural gas.

4 **Q. DO YOU AGREE WITH MR. FREEMAN THAT A MORE COMPLETE**
5 **ASSESSMENT OF MARKET PURCHASE OPPORTUNITIES WOULD HAVE**
6 **BEEN WARRANTED?**

7 A. No. As described in this testimony, a complete and meaningful assessment was made,
8 and it was our utility judgment that, for a variety of reasons, new generation at Cheyenne
9 will better serve customers of the two utilities.

10 **Q: MR. FREEMAN'S TESTIMONY REFERENCES THE FOLLOWING**
11 **COMMISSION DIRECTIVE FROM ITS ORDER ISSUING A CPCN FOR THE**
12 **WYGEN III FACILITY: "IN PARTICULAR THE COMMISSION EXPECTS A**
13 **FULL EVALUATION OF COMPETITIVE BIDDING FOR THE ENTIRE PLANT**
14 **AS WELL AS FOR SUBCONTRACTORS AND VENDORS (AS WAS DONE IN**
15 **THE CASE OF WYGEN III)." DO YOU UNDERSTAND THAT THE**
16 **COMMISSION HAS DIRECTED THE COMPANY TO EVALUATE THE COSTS**
17 **AND BENEFITS OF DEVELOPING FUTURE GENERATION PROJECTS**
18 **THROUGH COMPETITIVELY SOLICITING A TURN-KEY ENGINEERING,**
19 **PROCUREMENT, AND CONSTRUCTION (EPC) CONTRACTOR, AS**
20 **OPPOSED TO THE DEVELOPMENT OF AN OWNER SELF-BUILD PROJECT,**
21 **AS WAS DONE FOR WYGEN III?**

22 A: Yes.

1 **Q: HAVE BLACK HILLS POWER AND CHEYENNE LIGHT EVALUATED THE**
2 **COSTS AND BENEFITS OF DEVELOPING CPGS THROUGH**
3 **COMPETITIVELY SOLICITING A TURN-KEY EPC CONTRACT?**

4 A: Yes. The companies have conducted a competitive solicitation and evaluated bids for an
5 EPC contract to construct the facility.

6 **Q: AND HAVE THE COMPANIES ALSO SOLICITED BIDS FOR THE MAJOR**
7 **PROJECT COMPONENTS AND ENGINEERING IN ORDER TO EVALUATE**
8 **THE COST OF PROCEEDING WITH AN OWNER SELF-BUILD PROJECT, AS**
9 **WAS DONE IN THE CASE OF WYGEN III?**

10 A: Yes.

11 **Q: WHAT DID THE COMPANY LEARN ABOUT THE COST COMPARISON**
12 **BETWEEN AN EPC ARRANGEMENT AND THE OWNER SELF-BUILD**
13 **ARRANGEMENT THROUGH THIS COMPETITIVE BIDDING?**

14 A: The bid process revealed that the expected cost of building CPGS under an EPC contract
15 would be at least 10% greater than the expected cost under an owner self-build process.

16 **Q: IS THIS CONSISTENT WITH BLACK HILLS CORPORATION'S**
17 **EXPERIENCE IN EVALUATING THE PROJECT COSTS AND**
18 **CONSTRUCTION OPTIONS FOR OTHER FACILITIES?**

19 A: Yes. In an EPC contract, the EPC contractor guarantees a price and, in order to do that,
20 builds in a risk premium to compensate the contractor for the uncertainties associated
21 with the EPC contract. This premium is over and above any contingency amount in the
22 EPC contract to cover construction risks such as labor productivity and weather delays.
23 If an owner self-builds, the owner does not have to pay the EPC risk premium.

1 Q: MR. FREEMAN STATES THAT "BLACK HILLS CORPORATION, THE
2 PARENT OF BOTH CLF&P AND BHP HAS A REMARKABLY GOOD TRACK
3 RECORD OF CONSTRUCTING PLANTS AND BRINGING THEM INTO
4 COMMERCIAL SERVICE ON TIME AND WITHIN BUDGET," AND ALSO
5 SAYS THAT HE HAS "LITTLE DOUBT THAT BLACK HILLS CORPORATION
6 WILL BE ABLE TO CONSTRUCT [CPGS] ON TIME AND WITHIN BUDGET."
7 DO YOU AGREE?

8 A: Yes.

9 **VI. BUSINESS DECISION FOR JOINTLY-OWNED COMBINED CYCLE UNIT**

10 Q. CHEYENNE LIGHT FILED A CERTIFICATE OF PUBLIC CONVENIENCE
11 AND NECESSITY AUGUST 1, 2011 TO BUILD THREE COMBUSTION
12 TURBINE GENERATORS IN CHEYENNE. WHAT CHANGED AFTER THE
13 CPCN FILING?

14 A. After Cheyenne Light completed the analysis for its 2011 IRP, the modeling and analysis
15 for the Black Hills Power IRP was undertaken. That analysis showed the resource that
16 provided the least cost, least risk in the Black Hills Power preferred plan was the
17 conversion of a combustion turbine generator to combined cycle operation.

18 Q. WHY WAS THE OUTCOME OF THE BLACK HILLS POWER IRP
19 SIGNIFICANT?

20 A. When Black Hills Power began its IRP modeling, it assumed that if a CTG were to be
21 converted to combined cycle operation, it would be the CTG in Gillette, Wyoming. As
22 modeling proceeded and it appeared that the resource option that would be selected in
23 2014 was a CTG conversion, the Company began to consider the possibility that

1 converting CTGs to combined cycle in Cheyenne, Wyoming might be preferred. Those
2 CTGs would not have the same water or gas supply issues as existing CTGs in either
3 Gillette or Rapid City. The Black Hills Power IRP model was then revised to include the
4 option of a combined cycle (CC) conversion in Cheyenne, using one of the CTGs
5 identified in the Cheyenne Light IRP and a fourth CTG that would be installed by Black
6 Hills Power. This model run selected this configuration as the optimal resource for Black
7 Hills Power for addition in 2014. Company management then began to evaluate the
8 viability of a jointly-owned combined cycle unit located in Cheyenne that could possibly
9 satisfy the electricity needs of customers of both Cheyenne Light and Black Hills Power
10 and significant additional analysis was conducted.

11 **Q. DO YOU AGREE WITH MR. FREEMAN AS STATED ON PAGE 12 OF HIS**
12 **DIRECT TESTIMONY, LINES 1 AND 2, THAT NO HARD ANALYSIS WAS**
13 **UNDERTAKEN?**

14 **A.** No, I do not. It appears that in our direct testimony and our CPCN application, we may
15 not have conveyed the complete extent of the hard analysis that was undertaken. We did
16 not take lightly withdrawing our original CPCN application in order to file a new
17 application that requested different resources. I provide an overview of the additional
18 analysis that was conducted and the rebuttal testimony of Eric Scherr provides more
19 details.

20 **Q. WHAT ADDITIONAL ANALYSIS WAS CONDUCTED BY CHEYENNE LIGHT**
21 **AND BLACK HILLS POWER THAT LED TO THE SELECTION OF A**
22 **JOINTLY-OWNED COMBINED CYCLE UNIT IN CHEYENNE?**

1 A. For Cheyenne Light, additional capacity expansion modeling and production costing
2 modeling was conducted. The additional capacity expansion modeling added a jointly-
3 owned combined cycle unit as a resource option and allowed for 50 MW of firm market
4 purchases in all months of the year. This revised capacity expansion modeling selected
5 the jointly-owned combined cycle unit in addition to one CTG as the resource selection
6 within the resource portfolio for Cheyenne Light. The production cost modeling
7 confirmed the resource option selection for 2014 of the jointly-owned combined cycle
8 unit and a CTG. This analysis is documented on page 46 of the application.

9 For Black Hills Power, additional production cost modeling was conducted. This
10 additional modeling assumed that only 55 MW of a combined cycle would be available to
11 Black Hills Power rather than 95 MW of a CC as modeled in the original IRP analysis.
12 The results of this additional modeling are documented on page 47 of the application.
13 This analysis confirmed that a base scenario with a CTG to CC conversion in 2014 was
14 the preferred plan.

15 Upon completion of this additional modeling our resource planning personnel
16 undertook significant additional analysis to further understand the resource choice.

17 **Q. PLEASE DESCRIBE THE ADDITIONAL ANALYSIS CONDUCTED.**

18 A. A risk analysis that examined resource mix benefits, operational and environmental
19 benefits, and market benefits was undertaken as discussed on page 48 of the application.
20 Operational cost benefits of the combined cycle unit were examined as discussed on
21 pages 48-49 of the application. Analyses relating to capacity factor, load duration curve
22 fit, system regulation, operation, carbon emissions, and run hours were also conducted.

23 **Q. WHAT WAS THE CONCLUSION OF THE ADDITIONAL ANALYSIS?**

1 A. The conclusion was that there were significant benefits to the customers of both
2 Cheyenne Light and Black Hills Power as a result of building a jointly-owned combined
3 cycle unit in Cheyenne. Cheyenne Light then withdrew the already filed CPCN and filed
4 a joint CPCN application.

5 **VII. BUSINESS CASE FOR UTILITY-OWNED RESOURCES**

6 **Q. HOW DID CHEYENNE LIGHT AND BLACK HILLS POWER DETERMINE**
7 **THAT THE RESOURCES IN THE CPCN REPRESENT THE LEAST COST,**
8 **LEAST RISK OPTION?**

9 A. Before preparing the joint application for the requested CPCN, utility management
10 completed a thorough and careful analysis to determine that the proposed generation
11 would result in the least cost, least risk alternative for meeting each utility's individual
12 obligation to serve. In addition to evaluating the modeling results and additional analysis
13 referenced above, Cheyenne Light and Black Hills Power considered the possibility of
14 purchasing and owning existing generation, entering into additional purchased power
15 agreements (PPA), and constructing new generation. Our decision was to proceed with
16 utility-owned generation.

17 **Q. WOULD YOU PLEASE EXPAND UPON WHAT YOU SEE AS THE**
18 **ADVANTAGES OF UTILITY-OWNED GENERATION?**

19 A. I believe that there are operational benefits as well as financial benefits associated with
20 utility-owned assets.

21 **Q. WHAT ARE THE OPERATIONAL BENEFITS OF UTILITY-OWNED ASSETS?**

22 A. Utility ownership of generation assets provides operational benefits such as outage
23 management, dispatch, ramp rates, unit commitments, and capital additions for increased

1 efficiency and life extension and to comply with new regulations. When a utility owns a
2 generating unit, that utility has the ability to maximize the availability of the unit subject
3 to various economic considerations and take into account the outages and availability of
4 other units on its system. A utility can directly control the ramping up and down of
5 utility-owned assets in a manner that is most cost effective for the customers. A utility-
6 owned asset can be examined within the context of the utility's entire system to
7 determine if the unit commitment or dispatch needs to be handled differently in order to
8 optimize the operation of the entire system. Utility ownership can result in capital
9 additions to increase unit efficiency or additional maintenance to improve a unit's
10 performance as these investments are vetted through the regulatory process and borne by
11 the customers; provided the utility can demonstrate that the benefits exceed the costs.

12 **Q. WHAT ARE THE FINANCIAL BENEFITS OF UTILITY OWNERSHIP OF**
13 **GENERATION?**

14 A. Generation assets are going to earn a return for someone. If an IPP owns the assets, the
15 return is earned by a party that does not have an obligation to serve and that is not in need
16 of cash flow to reinvest back into the utility. If the utility owns the asset, the
17 Commission sets the authorized rate of return and the utility has the opportunity to earn
18 that return and thereby generate new funds for investment, thus allowing better debt
19 management.

20 **Q. ARE THERE TRADE-OFFS WITH UTILITY-OWNED GENERATION VERSUS**
21 **THE PROVISION OF ELECTRICITY THROUGH A PPA?**

22 A. Yes. At times, purchases from an IPP will be lower cost than the initial rates that a utility
23 needs to charge when it builds new generation. Over time, the utility rates decline with

1 depreciation and reduced rate base, while IPP charges frequently have annual escalators
2 that cause the cost to increase. In addition, often when the PPA terminates, the renewal
3 price reflects the market value of power, not the costs related to the generation providing
4 the power. Black Hills Power provides a valuable example. In 2002 Black Hills Power
5 constructed the Lange LM6000 40 MW combustion turbine power plant at Rapid City,
6 South Dakota for approximately \$30 million. By the end of 2011, the rate base related to
7 the Lange power plant was only \$19.8 million. Typically when utilities own their own
8 generation rather than relying on a PPA, customers experience declining costs.

9 **VIII. CURRENT INTEGRATION OF THE OPERATIONS OF CHEYENNE LIGHT**
10 **AND BLACK HILLS POWER**

11 **Q. ALTHOUGH THE IRPS WERE CONDUCTED SEPARATELY, DOES SOME**
12 **INTEGRATION AND COORDINATION BETWEEN CHEYENNE LIGHT AND**
13 **BLACK HILLS POWER CURRENTLY OCCUR?**

14 **A.** Yes.

15 **Q. COULD YOU PLEASE DESCRIBE SUCH INTEGRATION AND**
16 **COORDINATION?**

17 **A.** Black Hills Corporation provides centralized support services to its utility affiliates,
18 including Cheyenne Light and Black Hills Power, through two service companies: Black
19 Hills Service Company and Black Hills Utility Holdings. These services include:

- 20 • Centralized outage management
- 21 • Centralized customer support call centers
- 22 • Centralized IT operations and related software including accounting, customer
- 23 information systems (CIS), human resources , and so forth

- 1 • Centralized generation dispatch and power marketing
- 2 • Centralized administrative support including human resources, finance and accounting,
- 3 and regulatory
- 4 • Centralized generation resource planning, development and operations management
- 5 • Centralized engineering.

6 **Q. PLEASE PROVIDE A SUMMARY OF HOW THE IRP ANALYSIS,**
7 **ADDITIONAL ANALYSIS AND RESULTING BUSINESS DECISIONS OF THE**
8 **COMPANY LED TO THE CONCLUSION THAT THE RESOURCES FILED IN**
9 **THIS JOINT CPCN FOR CHEYENNE LIGHT AND BLACK HILLS POWER**
10 **REPRESENT THE LEAST COST, LEAST RISK RESOURCES.**

11 A. Cheyenne Light and Black Hills Power conducted separate IRPs reflecting the realities of
12 the operation of the two utilities today where the generation is separate but many other
13 functions are integrated. During the conduct of those IRPs and because of the results of
14 the modeling conducted, the companies had an opportunity to develop a jointly-owned
15 CC unit in Cheyenne, Wyoming that is expected to provide a wide range of benefits for
16 both companies while minimizing risk. Additional capacity expansion and production
17 cost modeling was conducted to verify the economics of making the business decision to
18 construct a jointly-owned unit. Market purchases in the form of contractual arrangements
19 with third parties were considered as a resource option during the modeling and were
20 selected. The companies considered other contractual arrangements, the benefits of
21 utility-owned versus purchased generation, and the conversion of coal-fired units to
22 natural gas in their analyses. We believe that a CTG and a jointly-owned CC located in

1 Cheyenne, Wyoming are the resources that should be selected for the 2014 timeframe and
2 request approval of our jointly-filed CPCN.

3 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

4 **A.** Yes, it does.

STATE OF Wyoming
COUNTY OF Laramie

SS

I, Kyle D. White, being first duly sworn on oath, depose and state that I am the witness identified in the foregoing prepared testimony and I am familiar with its contents, and that the facts set forth are true to the best of my knowledge, information and belief.

Kyle D White
KYLE D. WHITE

Subscribed and sworn to me this 18th day of June, 2012

Deborah L. Webber
NOTARY PUBLIC



My Commission Expires: June 23, 2015

Clients:

Mike and Patti Roth

P.O. Box 552

Parker, SD 57053

Phone: 605-297-2238

AUTHORIZATION REGARDING CLIENT FILES

The undersigned, a client of the Woods Fuller Shultz & Smith P.C. firm, hereby acknowledges receiving written notice of the withdrawal of Mary Akkerman from the firm of Woods Fuller Shultz & Smith P.C., and directs the firm to take the following action with regard to the client files, papers and property associated with those matters on which Ms. Akkerman has provided, or is providing, legal representation on my behalf:

(Check Each Applicable Line)

(1) ☒ Please transfer the following files to Lindquist & Vennum, attention Mary Akkerman at 100 S. Dakota Avenue, Sioux Falls, SD 57104:

(a) ☒ All of my client files

(b) ☐ Only the following files: _____

(2) ☐ Please transfer the following files to _____ [please insert the name of your chosen attorney] at the Woods Fuller Shultz & Smith P.C. law firm:

(a) ☐ All of my client files

(b) ☐ Only the following files: _____

(3) ☐ Please retain all of my files at Woods Fuller Shultz & Smith P.C. law firm, except those listed in lines (1)(b) and (2)(b) above.

3/22/2012
Date

Patricia G. Roth
Signature of Client or Client Representative

Title (if applicable)